

BEFORE THE  
WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01\_\_\_\_\_

EXHIBIT NO. \_\_\_\_\_ (KON-14)

WITNESS: KELLY O. NORWOOD, AVISTA CORP

Exhibit No.\_\_\_\_(KON-14)

Docket No. UE-\_\_\_\_\_

## Contents

Related links: [This document as a 1MB Acrobat PDF file](#)

[Introduction](#)

[Summary](#)

[Recommended Actions](#)

[Background](#)

[Status of Electricity Markets](#)

[Causes of Current Market Conditions](#)

[Electricity Outlook for 2001](#)

[Policies to Address Shortages](#)

[Enhancing Supply](#)

[Emergency Hydro, Spill Reduction, and Out-of-Region Purchases](#)

[Increasing Generation](#)

[Possibilities for Enhancing Thermal Generation](#)

[Reducing Consumption](#)

[Getting the Signals Right - Prices](#)

[Demand Management](#)

[Efficiency Improvements](#)

[The Value of Public Leadership](#)

[Controlling the Market](#)

## Introduction

There is significant regional concern about electricity supplies and prices for the rest of 2001 and beyond. Our analysis indicates that this concern is well-founded. The purpose of this paper is to clarify the electricity situation for 2001, to note the actions that are being taken to address the problem, and to urge additional actions that can be taken to help improve this year's prospects for meeting electricity needs while minimizing impacts on fish programs and the regional economy.

## Summary

Western electricity markets are headed for a difficult summer and possibly a difficult winter of 2001-02 as well. Current poor water conditions translate into continued tight electricity supplies for the rest of 2001. The accompanying high electricity prices could combine with a general slowdown in economic activity to create difficulties for many of the region's businesses and citizens. This paper does not focus on conditions beyond 2001, and no inferences regarding the future adequacy and reliability of power supplies should be drawn beyond this time frame. Longer-term issues will be addressed in future analyses.

In order to meet regional loads this winter, the region has had to rely on emergency operation of the hydrosystem, drawing down reservoirs below the levels established by the 2000 Biological Opinion on Operation of the Federal Columbia River Power System issued by the National Marine Fisheries Service. It is a virtual certainty that these emergency operations also will be necessary during this spring and summer to keep the electricity system from suffering outages. In addition, it is likely that substantial reductions in spill will be necessary.

The use of emergency hydro and spill reduction and their possible effects on fish can be at least

partially mitigated by taking actions to reduce demand, increase in-region generation and purchasing power that may be available from the market during the spring. However, the latter, in particular, may have a high cost to the region's utilities and economy. As we approach the end of summer, restoring reservoirs to levels called for in the Biological Opinion (BiOp) is important for reliability in the fall and winter as well as for meeting salmon targets for flows in 2002. Achieving this is likely to require reductions in the spill called for in the BiOp. The difficult tradeoffs facing the region involve electricity reliability, salmon recovery goals and costs to the region's utilities and the regional economy. To the extent that additional generation and demand reduction can be achieved this summer at costs lower than expected market prices, this trade-off will be more manageable.

## **Recommended Actions**

Individuals, businesses and utilities are already taking actions that will help achieve some of these goals. However, there are additional actions that need to be taken by regional leaders as soon as possible. These are listed below:

- Public leaders should continue to inform and educate the public about the electricity problems faced by the region this year. Public awareness can be one of our most effective tools.
- Parties in the region need to come to agreement about hydropower operating strategies for the summer that prioritize water usage to strike an appropriate balance among reliability of electricity supply, costs to the region's economy, the financial health of the region's utilities and salmon recovery goals.
- Utility regulators should support and expedite utility programs to implement emergency demand management programs.
- Siting and environmental agencies should expedite emergency siting of short-lead-time generation while still protecting the longer-term societal interests.
- The region's utilities should seek to bring existing emergency standby generation into the grid. Environmental agencies should cooperate by expediting temporary operating permits for such facilities, if necessary.
- Environmental agencies should work to temporarily relax restrictions that prevent existing generating plants from continued operation at full capacity, without jeopardizing public health and safety.
- Utilities and public agencies should expand the scope and funding of existing energy efficiency programs that can be expected to deliver savings in the short term.
- Utilities, Bonneville Power Administration (BPA), and regulatory agencies should begin the process of designing electricity pricing structures that provide price signals to help develop demand response to prices and shortages.
- State and local agencies should ensure that low-income assistance programs are adequately funded to respond to impacts from high electricity prices.

## **Background**

### **Status of Electricity Markets**

Wholesale electricity markets in the West are in serious trouble. Prices since last winter have increased from between \$25 and \$30 per megawatt-hour to several hundred dollars per megawatt-hour. Utilities in California are on the verge of bankruptcy, the state has stepped in to acquire electricity supplies, and is also considering buying the transmission system. California has been operating in Stage 3 emergency conditions much of the winter. The Pacific Northwest has been forced to implement emergency operations of the Columbia River hydropower system to keep from interrupting electricity supplies, but this presents risks to threatened and endangered fish species.

Many consumers have been insulated from higher prices so far. In California, consumer prices were frozen by law. In the Northwest, many publicly owned utilities buy all of their power from BPA. Other utilities have their own generating resources that have been adequate to meet loads without

reliance on spot markets. However, even what seemed like a reasonably small exposure to spot markets for some utilities has turned into huge rate increases to the utilities' consumers because of the extremely high wholesale prices. Beginning in the new rate period in October 2001, BPA customers may also be exposed to some very large rate increases based on the need to acquire a few thousand megawatts of additional electricity to meet subscription loads.

## **Causes of Current Market Conditions**

It is important to understand that the electricity market situation in the West is extremely unusual. This is not what should be expected of an even modestly well-functioning restructured electricity market. The reasons for the dramatic price excursions we have been experiencing are several and are interrelated. They include an immature and structurally flawed electricity market; the simultaneous occurrence of high prices in natural gas and oil; poor water conditions; adverse weather; and generating capacity that has not been keeping up with the growth in electricity demand. It is extremely bad luck for poor water, adverse weather, and all major energy commodity cycles to coincide, but for it to occur when electricity markets are in such a fragile state is extraordinary.

The Council's "Study of Western Power Market Prices: Summer 2000" described the problems in the electricity market. There are two dominant characteristics of the current Western electricity market that are at fault. First, the demand side of the market has not yet developed. Price signals are not getting through to consumers as retail prices. Second, customers and utilities that are exposed to market prices have not adequately protected themselves from market price risk. In California, both of these characteristics were designed into the restructured electricity market. The consequences of these characteristics were not clear until hot temperatures and poor hydroelectric conditions exposed the growing shortage of capacity in the market last summer.

The fact that electricity capacity has become short, may itself be due to the very recent restructuring of electricity markets. There have been, and remain, significant uncertainties about the future structure of electricity markets, and the plans are inconsistent among the states in the West. This kind of uncertainty has made the private sector reluctant to commit capital to new generating capacity. Beyond this, the Council's "Northwest Power Supply Adequacy/Reliability Study" raised some issues about whether adequate capacity would be maintained even in a well-structured and mature electricity market. But that is a longer-term issue than we wish to address in the current paper.

Understanding that the current situation is unique is important background for considering actions to help the region through the coming year. One should not underestimate the magnitude of the change involved in moving to a more competitive electricity market. The inertia is huge and, as in the case of California, policies sometimes work against the transition instead of furthering it. Unless one believes it is possible to reverse the nationwide move to a competitive wholesale power market, actions should be considered that help develop a viably competitive wholesale market while helping to alleviate the current shortages.

As disruptive as the current shortage and high prices are, they are rapidly forcing the development of new supplies and improved demand-side responses in the electricity market. New electricity generating plants are being started to supplement supplies. But the responses are not limited to the traditional generation solutions; smaller distributed technologies are gaining favor, demand-side changes are being sought by utilities and found, and increasingly, demand-side opportunities are being volunteered to utilities as high prices and slowing economic conditions affect businesses in the region. These responses to the high electricity prices will help alleviate, but not eliminate, the electricity supply problems this summer. But in the longer term they will forge new relationships and approaches that will make the future wholesale electricity market more efficient and competitive by diversifying the supply alternatives available and making demand more responsive to market conditions.

These adjustments have a dark side, however. Emergency reductions in electricity use by businesses often mean reduced production and loss of jobs. Higher wholesale prices, passed on to residential customers mean increased expenditures for electricity and less money left over for other purposes. Low-income consumers can be especially hard hit because energy bills are a larger portion of their already tight budgets.

Below, we document in more detail the expected electricity supply for the coming months and the responses taking place in the electricity markets. We then look at the limited policy alternatives for helping the region make it through the coming summer.

## **Electricity Outlook for 2001**

2001 promises to be another difficult year for the Northwest power system and, in fact, for the West as a whole. The "meltdown" of the California market of last year was triggered, in part, by an unusual Northwest rivers runoff pattern that resulted in significantly less power in the market last summer than has been the case in recent years. This unmasked an underlying overall supply shortage resulting in the run-up in prices.

While 2000 was near normal in terms of overall runoff, 2001 is starting off as a very poor water year. The current January-July runoff forecast is approximately 55 percent of average, assuming normal precipitation for the March-July period. There is only one year in the 60-year record with lower March through July runoff. If dry conditions persist, this could be one of the poorest hydro years on record. Using 1944 water conditions, a year with just slightly higher runoff than the current projection, "normal" hydropower generation is approximately 4,700 average megawatts less than average over the March through August period. Using 1977 water conditions, the lowest on record, the March through August "normal" hydropower generation is over 5,000 average megawatts below average. If the region DOES NOT take extraordinary steps in the operation of the hydropower system or purchase substantial amounts of power on the market at what are almost certain to be very high prices, we could face significant deficits this spring and summer. For 1944 water conditions, the total energy deficit across the months of April through August is 5,600 megawatt-months. The maximum monthly deficit is approximately 2,700 megawatt-months in May. For 1977 water conditions, the total April through August deficit is almost 8,000 megawatt-months, with the May deficit reaching 3,300 megawatt-months.

## **Policies to Address Shortages**

There are steps that can be taken in the operation of the hydropower system that can significantly reduce or eliminate these summer deficits. Additional generation can be achieved through operating outside the BiOp constraints -- drafting reservoirs deeper and reducing spill. Loads can be reduced through contract buyouts, conservation and demand exchange efforts. However, the choices we make will have implications for our ability to continue to meet load through the fall and winter of 2001-02. These alternatives and the choices involved are examined in the following section. However, even with such operations, it is likely that this summer will be a period of tight supplies and continued high market price.

The realistic options for policy makers to help negotiate a path through this summer's electricity problems are limited. Some new generation capacity is expected to come online in time to help this year, and the use of hydrosystem flexibility will improve electricity supplies. The rest of the problem can only be addressed by reducing electricity consumption. High wholesale prices and forecasts of increasing retail prices are already stimulating actions by consumers and utilities.

## **Enhancing Supply**

## **Emergency Hydro, Spill Reduction, and Out-of-Region Purchases**

As noted earlier, there are steps that can be taken in the operation of the region's hydroelectric system to increase generation above that which can be achieved if the system is operated strictly to the constraints of the BiOp. These steps, however, typically involve trade-offs. For example, if water conditions were not to get significantly worse than the current runoff forecast, the region could meet its loads across the spring and summer through the use of "emergency hydro" alone.

Emergency hydro involves generating additional energy by drafting the system deeper than the constraints established in the BiOp. This, however, would reduce summer flows and leave the reservoirs at the end of August at levels that significantly reduce the ability of the power system to meet loads through the fall and winter, assuming the ability to purchase imports is limited. If water conditions deteriorate to those of 1977, use of emergency hydro alone would not solve the spring and summer reliability problems and would leave the reservoirs in even worse condition at the end of August.

Staff has done a preliminary analysis of the region's ability to serve load across the 2001-02 winter. That analysis compares starting the reservoirs in September at the level called for in the BiOp with starting the reservoirs at the lower level that would result from using emergency hydro alone throughout this spring and summer with 1977 water conditions. The analysis further assumed that beginning in September, the lower two thirds of the historical water years were possible. This reflects a weak relationship between spring and summer runoff and the runoff in the subsequent fall and winter. The analysis estimates the probability of meeting load with water conditions, temperatures and therefore demand for electricity, and forced outages varying randomly. The analysis assumed that there is some ability to purchase imports through the fall and winter up to 2,250 average megawatts.

With the caveat that this is a preliminary analysis and the results may change, it indicates the probability of being unable to fully meet loads at some time during the winter (December through February) increases from approximately 20 percent to 45 percent when starting the reservoirs at the lower level. The probability that for any day in January loads would exceed supply at some level goes from 7 percent to 15 percent, with the maximum daily observed energy deficit going from 8,800 to 11,000 megawatt-days. For this reason, we believe that operating the hydropower system across the spring and summer to achieve BiOp reservoir levels at the end of August is a very important consideration.

To get through the summer reliably and achieve BiOp reservoir levels at the end of August will require either extensive purchases from outside the region and/or significant reductions in spill. The availability and cost of out-of-region purchases is problematic. Even if the power is available, it could be very expensive. With significant reductions in spill in conjunction with use of emergency hydro, it would be possible to maintain a reliable system across the spring and summer and leave reservoirs very close to BiOp levels going into the fall. This obviously raises questions regarding the impacts of significantly reduced spill on survival of downriver migrants.

However, it should also be noted that reducing spill also provides some additional flexibility and possible value to the hydropower system. Staff has estimated preliminarily that by eliminating spill entirely and using emergency hydro, with 1944 water conditions the system would retain water with an energy equivalent of approximately 5,500 megawatt-months. For 1977 water conditions, this figure drops to about 1,600 megawatt months. The bulk of this retained water/energy is available in July and August. There are several uses to which this could be put. To a limited degree, some of the water could be retained in the reservoirs resulting in higher reservoir levels at the end of August and more hydropower for use in the ensuing fall and winter. Some of the eliminated spill could be restored. Or the energy could be generated, coincidentally increasing flows in the river. The period in which it would be available coincides with the peak demand months in the Southwest. Some of this energy could be used to help meet the Southwest's demands and would generate much-needed revenues, some of which might be used for additional salmon recovery projects. As an alternative, it might very well be possible to negotiate energy exchanges with California utilities that help the

Northwest in the fall and winter and help California in the summer. Moreover, additional energy in the market this summer would serve to hold down market prices to some degree throughout the West.

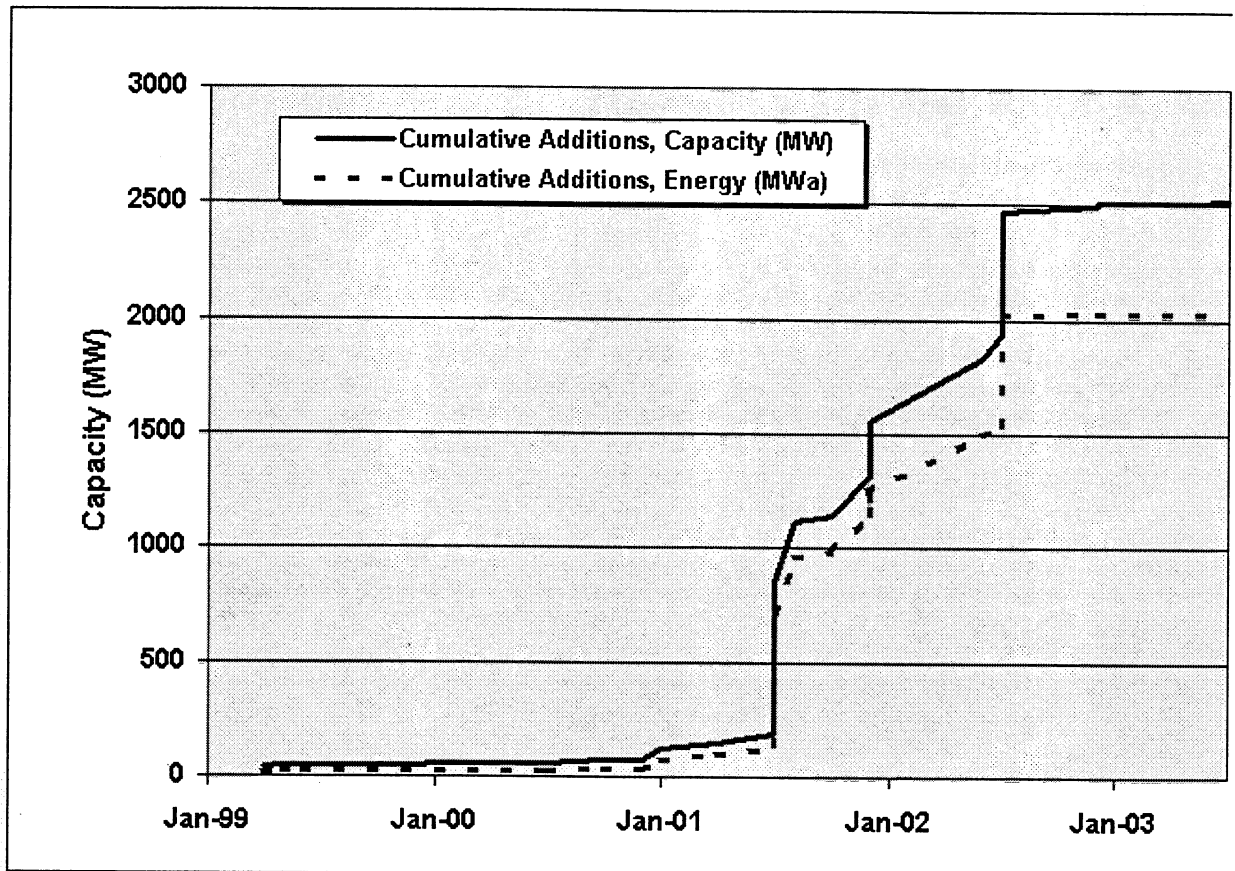
To maintain reliability, restore reservoir levels, maintain the economic health of the region's economy and its utilities, and not unduly impair salmon recovery goals without additional runoff will be extremely difficult and will require thoughtful and careful balancing. Additional in-region generation and demand reduction will make that balancing easier but not easy. The region needs to come together on an operating strategy that achieves the appropriate balance, and do so soon.

## **Increasing Generation**

Northwest generating capacity development has greatly increased following a several-year hiatus. About 800 megawatts of capacity is expected to enter service during the first half of 2001, and an additional 700 megawatts should be available by winter 2001(Figure 1).

About two-thirds of the resource additions shown in Figure 1 are gas-fired combined-cycle combustion turbines. Klamath Cogeneration (484 megawatts) is scheduled for service in July 2001. Rathdrum (270 MW) is on an accelerated schedule for mid-July completion. Coyote Springs 2 (280 megawatts) and the Hermiston Power Project (536 megawatts) will follow in summer 2002.

Hydropower upgrades, wind and other renewables comprise about 18 percent of the 2003 total. Upgrades at Lower Baker, Rocky Reach, Cabinet Gorge, Little Falls and other hydro projects will supply about 80 additional megawatts of capacity and about 60 average megawatts of energy. FPL Energy, developer of the 300-megawatt Stateline wind project northeast of Pendleton, Oregon, expects at least two-thirds of the project to be operating by winter 2001. The remainder of Stateline and the 25-megawatt Nine Canyon wind project near Richland, Washington, should enter service during 2002.

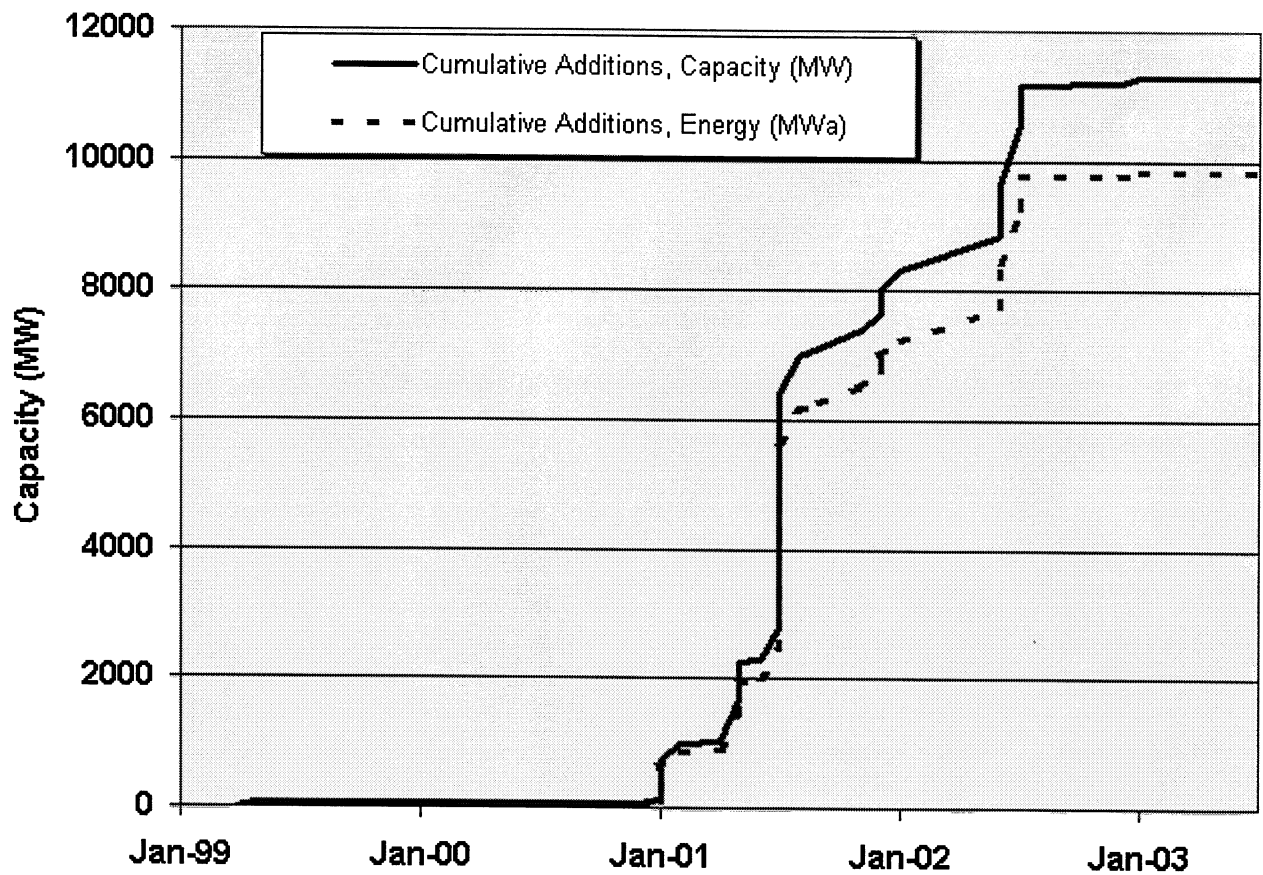


**Figure 1: Pacific Northwest generating resource additions**

In recent months, several Northwest utilities and industrial consumers have been working to secure and site short lead time generating equipment to meet near-term reliability needs. More than 500 megawatts of new peaking capacity, some temporary, is planned for 2001 service. This capacity will consist of simple-cycle combustion turbines and diesel-generator farms, fuelled by oil or natural gas. Temporary diesel farms are already in operation at Tacoma (48 megawatts), the Georgia-Pacific Bellingham mill and the Cherry Point refinery (26 megawatts). Others will enter service through the remainder of 2001.

Electricity prices in the region are affected by the conditions in the entire interconnected western electricity market as defined by the Western Systems Coordinating Council (WSCC). Energy balance in the Pacific Northwest would not necessarily imply lower wholesale electricity prices if the rest of the West remained resource short. For the WSCC area as a whole, about 6,900 megawatts of new generating capacity will enter service between January and July 2001. These figures include about half of the 2,100 megawatts of emergency peaking capacity sought in California for summer 2001, an estimate considered reasonable by California observers. An additional 1,300 megawatts of new generating capacity is scheduled by the end of 2001 (Figure 2). As in the Northwest, the majority of new additions are combined-cycle combustion turbines fuelled by natural gas.

Whether these capacity additions, and others that may develop in the WSCC and the Northwest, are adequate to balance demands and bring electricity prices down after 2001 depends on the levels of demand, availability of hydroelectricity in future years, and expansion of natural gas supplies and pipeline capacity. These issues will be addressed in future analyses.



**Figure 2: West-Wide generating resource additions**

## **Possibilities for Enhancing Thermal Generation**

### **Additional capacity in the near-term**

Sources of additional generating capacity by summer 2001 include packaged generation, reactivation of idle units and operation of distributed emergency generating units. Packaged reciprocating engine generator sets and gas turbine generator sets are commercially available, though increasingly difficult to secure in the near term. Capacities range from less than one to about 100 megawatts. Natural gas operation is generally lower cost but presents concerns regarding nitrogen oxide emissions. Fuel oil provides greater siting flexibility but presents problems of sulfur dioxide and particulate matter as well as nitrogen oxides. Noise and vibration may be issues in both cases. Prospective sites require transmission interconnection capability and fuel supply. The major keys to the near-term development of additional generating capacity are securing equipment, expeditious permitting and overcoming local objections.

Some idle generating capacity might be reactivated for near-term operation. Our records show about 130 megawatts of idle capacity in the region, primarily small cogeneration plants associated with the wood products industry. Most operate on wood residue, though some could use fuel oil or natural gas. The feasibility of reactivating these units would have to be determined on an individual basis.

Emergency generating units are found in many power plants, office buildings, hospitals and at other large commercial and industrial sites. These range in size from a few kilowatts to several megawatts. Most are reciprocating engine generator sets and some are small gas turbines. Most use fuel oil. The principal issue is whether these units could be routinely dispatched to serve load without compromising their primary function, which is to provide emergency backup. Other issues include coordination of operation, air quality impacts, noise and vibration. The feasibility of using these units for routine generation units must be determined on an individual basis. Portland General Electric and Grant PUD have reported some success in securing agreements for operation of these facilities.

### **Permitting**

In general, any relaxation of the permitting processes and standards for permanent base-load generation would have little effect on the electricity problem for this summer and fall. Because of 12 to 24-month construction periods, permitting will not affect the amount of permanent generation that can be completed this year. Moreover, there is a significant amount of generation sited and under development. By winter 2003, at least 2,500 megawatts of permanent capacity will have been placed in service in the Northwest since release of the Council's Adequacy and Reliability Study of March 2000. This represents over 80 percent of the 3,000 megawatts of supply and demand-side resource additions that that study found to be needed to restore conventional loss-of-load probability by winter 2003 (Figure 1). Some believe this indicates the siting processes are effective where they have been tested by real proposals, mostly in Oregon and Washington. However, some in Montana believe that their siting process has been a deterrent to development, and efforts are being made to streamline future permitting processes to reduce unnecessary delays while still maintaining environmental standards.

Permits are in effect for more than 2,600 megawatts of combined-cycle capacity not yet under construction. Permitting is under way for an additional 8,500 megawatts of combined-cycle plant, including the contested Sumas 2 project in Washington state. Not all of the permitted sites are

ideally situated for development, and in not every case do developers appear to be actively pursuing permitted projects. However, several of the permitted sites are excellent prospects for development. The principal impediments in these cases appear to be equipment availability and securing the commitments to buy the output, which are required for project financing.

An exception to these recommendations is permitting of the short lead time projects discussed earlier. Expeditious permitting is essential for these options to be effective. But, while permitting must be quick, environmental impacts cannot be ignored. Temporary installations have a way of becoming permanent. Local opposition can contribute to the removal of poorly sited units, as in the case of the Bethel plant in Oregon. A basic criterion for accelerated permitting would be a time limit on operation, following which the plant could be permitted using conventional processes and criteria. Other criteria might include compliance with basic "bright-line" environmental criteria, similar to the approach used for accelerated California permitting.

### **Maintenance schedules**

Scheduled maintenance outages were a factor contributing to the high wholesale power prices of June 2000. Though scheduled outages extending into June have been common practice in the Northwest, early snowpack runoff and high Southwest loads in 2000 combined to create need for additional June generation. A similar situation is likely this year. Because of proprietary concerns, there is no longer overall outage coordination in the Northwest. Forecast power prices and futures markets are thought to provide sufficient incentive for operators to schedule maintenance during lower price periods. However, improved information such as posting of outage plans, runoff expectations or near-term price forecasts would be desirable.

A special case for the Northwest is the Columbia Generating Station (CGS) nuclear plant. A 30-day refueling outage is scheduled to begin on May 18. While 30-day outages have been achieved in the past, this schedule will be challenging because of the large number of fuel bundle transfers needed for the transition from an 18 to a 24-month refueling cycle. Failure to meet the target schedule will push the outage further into the anticipated high demand period of June. While the schedule could be shifted forward to improve the probability that the plant will be operating for peak early-summer loads, such a move at this time would be disruptive and result in less efficient use of fuel.

### **Air quality restrictions**

Last year, the operations of some Northwest combustion turbines were constrained by air quality restrictions. Puget Sound Energy, the operator of about 70 percent of Northwest combustion turbine capacity, reports that arrangements, including retrofits of additional pollution control equipment, have been made that will allow its units to operate without interruption this summer.

## **Reducing Consumption**

While the supply of new generating capacity is increasing, there is still a significant probability that regional demand for energy will not be met. Therefore, there is a need, and significant opportunity, for actions that will reduce consumption and bring demand closer to the available supply. These activities include correcting price signals, facilitating voluntary demand reductions, and enhancing the acquisition of energy efficiency.

## **Getting the Signals Right - Prices**

The vast majority of electricity consumers pay electricity prices that are poor indicators of the actual cost of providing electricity. This problem has two dimensions: first, most retail prices are based on average cost rather than marginal cost (the cost of providing an extra unit), and second, retail prices vary little or not at all with season or time of day. This, in spite of the fact that the cost of generating and delivering electricity can vary by several hundred percent depending on the time of

day and season of the year. Last year's wholesale prices demonstrated even more volatility than we can attribute to the cost of generation.

This disconnect between real time wholesale prices and retail prices is a fundamental deficiency in the electricity market and contrasts with the markets for most goods and services. For most goods and services, consumers see price variation that reflects supply conditions: when oil production is reduced in the Middle East, consumers are not surprised to pay more for gasoline; when Florida orange groves suffer frost damage, consumers are not surprised to pay more for orange juice; consumers are not surprised to pay more for tomatoes in January than in July. These price variations give consumers incentives to respond by buying substitutes, adjusting the timing of their purchases, or by simply buying less of a product that is currently more expensive than its value to them.

Without variation in retail prices to reflect supply conditions, electricity consumers lack the incentive to change their usage patterns. Even when the marginal kilowatt-hour is costing the power system 50 cents to a dollar, consumers continue to use electricity as if it cost 2.5 to 10 cents, because that is the cost to them. Thus we might see electricity that cost the power system \$5.00 being used by an industrial customer to produce a product that sells for 80 cents (with an operating profit of no more than 20 cents). It makes sense to industry, given the cost it sees, but it makes no sense to the system as a whole.

Without some remedy to this problem, the system will continue to provide too much power (i.e. more than customers would buy if they saw the actual cost), and at average prices that are higher than necessary. When supplies are particularly tight, unresponsive demand magnifies increases in wholesale prices.

The simple (at least in theory) prescription is to charge marginal cost for customers' marginal use, with retail prices that change hourly and reflect hourly supply conditions. Customers facing such "real time pricing" would have proper incentive to reduce or shift use in response to current conditions, or to invest in energy efficiency measures in response to expected prices over the long run. This need not have a disastrous impact on the total bill of the customer. The important point here is that marginal use should see marginal cost. Rates can be structured to accomplish this without raising the price of all use. Real time pricing might be a reality in the future, but for many reasons (e.g. the limitations of existing meters and contracts, customer and regulator acceptance) it is not a realistic option for many customers today. Some regional utilities and regulators are already exploring rate structures that include or approximate real time pricing. Broad development and adoption of such rate structures would go a long way toward creating an efficient electricity market that avoids many of our current problems.

## **Demand Management**

In the meantime, there are at least partial remedies that can be put in place quickly; in fact, we've seen significant progress in the last few months and more progress seems possible. These remedies can be separated into three broad categories: 1) voluntary curtailment, which reduces electricity use by reducing the level of comfort or services (e.g. lighting levels, indoor air temperature or industrial production); 2) demand shifting, which does not necessarily reduce total electricity use but changes its timing; and 3) efficiency improvements, which reduce electricity use but maintain the same level of comfort or service. All three categories of reductions can be appropriate and useful responses to tight supply conditions such as the region faces this year. All three responses are reduced when price signals are missing or distorted. In general, voluntary curtailment and demand shifting can be put in place more quickly. Energy efficiency may take longer to implement, but efficient equipment continues to provide savings throughout its life.

The term "demand management" is used to refer to programs designed to achieve either voluntary curtailment or demand shifting. These two approaches are discussed together in this section.

curtailment or demand shifting. These two approaches are discussed together in this section because demand shifting is essentially curtailment with a compensating increase in use at a more economical time, and because similar incentives apply to both. The problem facing the Northwest this year is primarily an energy problem. This means that actions that actually reduce demand are most beneficial. However, there remain differentials between peak period and off-peak period market prices. Consequently, demand shifting can reduce costs and help control peak period prices.

In the absence of efficient price signals, utilities are developing an assortment of "second best" demand management programs. The programs are designed to achieve responses similar to those expected from efficient prices. Most of them pay customers for reducing load, instead of charging the marginal cost of serving load. If the customer is willing to reduce load for a payment that is less than the marginal cost of providing power, the customer, the utility and the rest of its customers can all be better off. The main advantage of these mechanisms, compared to real time prices, is that these mechanisms are available now, when there is a critical need, and they provide reasonably predictable results once they are in place. There are disadvantages, too; these mechanisms require negotiation and administration, creating transactions costs that make it necessary for utilities to limit the number of customers who can participate.

### **Types of demand management mechanisms**

These mechanisms can be put in three broad categories. The first is traditional interruptible contracts, which offer the customers a reduction in electricity price in exchange for the utility's right to interrupt service under specified conditions. Most of these contracts were originally designed to provide the option of a quick and certain reduction in load to protect system stability, and were not expected to be exercised often.

Interruptible contracts appear to have a continuing role in supporting the system's stability, but it may well be more difficult to recruit participants in the future, now that actual exercise of the interruption is recognized as a real possibility.

The second category includes mechanisms that are flexible, intended to be exercised multiple times, responding to recurring supply conditions. They were originally designed to respond to limited supply or high price conditions expected to last for hours at a time, but they can be applied to more extended shortages such as this year's. These mechanisms involve an offer made by a supplier to pay for load reductions on a specified day, for specified hours. Customers who are willing to reduce their load in the specified period respond, the supplier notifies customers whose offers are accepted, and the process repeats whenever the supplier needs reductions. Examples of this category are:

- B.C. Hydro's Price Dispatched Curtailment program
- Demand exchange programs offered by Bonneville, Portland General Electric, PacifiCorp and Snohomish PUD
- Avista Utilities' program, an open offer of a fixed price for 24-hour blocks of load reductions

These demand exchange and similar mechanisms will be useful even in years when supply is not so limited as it is this year. Even in a year with generally adequate supply, there are likely to be short periods when the balance of demand and supply is tight, and customers might very well be willing to reduce loads for compensation that is less than the marginal cost of supply.

The third demand management category includes mechanisms that have been negotiated on a one-time basis, responding to this year's persistent supply problem, and are expected to last for months. These negotiations generally have resulted in reductions in loads for the rest of the fiscal or calendar year. Reductions after that would be the subject of new negotiations. Examples of these negotiated reductions are the agreements between:

- Bonneville and its direct service industries customers
- Springfield Utility Board and Globe Metallurgical Inc.
- Proposed agreements between Idaho Power and a number of irrigation customers

- Chelan County PUD and industrial customers
- Grant County PUD and industrial customers

Longer-term buyouts, lasting for several months, are useful in a year like this one, but they have significant impacts on the local economy. We wouldn't expect to see these mechanisms used in more normal years.

### **Potential load reductions from these mechanisms**

Programs in the last two categories are very new. They have delivered useful amounts of load reduction, and offer promise of more. For example, between June 2000 and March 2001 the aluminum industry loads on Bonneville have been reduced by about 1,300 megawatts. The reduced aluminum industry consumption has been available to serve other loads and reduce emergency operation of the hydro system. We can hope that more customers will be able to participate as utilities streamline and extend the programs, but we can't say what the number of participating customers might be ultimately. We can expect customers to think of more ways to reduce load, with more time to think and perhaps invest in equipment that makes reductions possible, but any quantitative estimate is at best a very rough one.

Keeping these limitations in mind, we could make such an estimate by applying the percentage reduction in peak load achieved by PGE's Demand Exchange (4 to 5 percent) to an assumed regional peak load of 36,000 megawatts. This suggests the additional ultimate potential could be in the range of 1,440 to 1,800 megawatts beyond the aluminum industry reductions noted above. We might not reach this potential this summer, because PGE is ahead of most utilities in the development of its program, but in the longer term, this potential could even be conservative as more customers are included in programs.

The more important lesson to take from the early experience is not how much total reduction we may be able to get, but that it's very likely that we can get more than we have so far. These programs are based on voluntary agreements; in contrast to rolling blackouts, no one is forced to go without power. We should try to make the programs available to as many customers as possible.

### **Efficiency Improvements**

The Northwest has relied heavily on this form of demand reduction to provide a significant portion of the new resources required. The Council estimates that since 1980, more than 1,400 average megawatts of energy efficiency has been acquired. Unfortunately, many of the utility programs responsible for this accomplishment were ramped down significantly in the late 1990s in the face of uncertainty regarding deregulation. Just like their supply-side counterparts, many of these programs and the infrastructure to support them take significant amounts of time to develop. However, there are some actions that can be taken to quickly accelerate existing programs and provide near-term conserved energy. The improved efficiency from these actions will continue to provide value in the future.

The following is a list of some of the most promising areas for quick-response energy efficiency programs. Combined, they represent 224 average megawatts, or almost the annual output of a new combined cycle gas-fired combustion turbine:

- **Replace Existing Incandescent Bulbs and Fixtures with Compact Fluorescent Bulbs and Fixtures:** Compact fluorescent bulbs produce the same amount of light using just 25 to 30 percent of the electricity used by standard incandescent light bulbs. If each of the roughly 4.5 million households in the region replaced just three incandescent light bulbs with compact fluorescent bulbs it is estimated that the region could save 100 average megawatts or enough to power the City of Springfield, Oregon for a year. Consumer awareness of electricity shortages and prices has already begun to stimulate retail sales of these products. In addition, many regional utilities are already moving to further encourage this activity.

Additionally, many regional utilities are already moving to further encourage this activity. PacifiCorp, PGE, Bonneville and other regional utilities have joined a regional lighting initiative through the Northwest Energy Efficiency Alliance's Energy Star marketing program to offer rebate coupons to their customers.

- **Upgrade Existing Commercial Building Lighting Systems:** Many of the region's existing commercial buildings can be cost-effectively retrofitted with the same energy efficient lighting technologies that are now required by new buildings codes. Replacing older, less efficient lamps and ballasts in overhead fluorescent lighting with modern, high quality lamps and electronic ballasts can reduce energy use by as much as 30 to 50 percent. There are additional energy savings from changing out old, incandescent display lighting with newer more efficient sources. Retrofits such as these made up much of the savings accomplished by the utility programs in the 1990s. Yet many buildings still use the older, less efficient and lower quality lighting systems. If just 10 percent of the region's commercial buildings reduced their lighting energy use by 30 percent, the region could save an average of 45 megawatts, or enough to energy to supply the city of Redmond, Washington, for a year.
- **Tune Up Heating, Ventilating and Air Conditioning Systems in Existing Commercial Buildings:** Complex commercial buildings, just like modern automobiles, should have regularly scheduled tune ups to make sure their heating and cooling equipment is operating properly and that the controls are calibrated. Experience from utility sponsored programs in this and other regions across the country have shown that such "tune ups" or "re-commissioning" can reduce electricity use by 10 to 20 percent, without equipment replacement. In this initiative, particular attention should be focused on making sure that existing "economizer" cooling equipment is operating properly. If just 5% of the region's existing commercial floorspace could be tuned-up, we could reduce regional electricity consumption by 22 average megawatts, or enough energy to supply Oregon City, Oregon, for a year.
- **Replace Existing Electric Motors:** Motors are the single largest consumer of electricity in the industrial sector using roughly 60 percent of the energy used by non-direct service industries. The new generation of "premium efficiency" electric motors are 2 to 6 percent more efficient than those produced just 10 years ago, and as much as 10 percent more efficient than the motors currently installed in many facilities. When an existing large motor fails, it is now common practice in industry to refurbish or "rewind" rather than replace the motor with a new model. Research has shown that "rewinding" electric motors if not done properly degrades their energy efficiency. Given current electric rates, it will make economic sense in some circumstances to replace functional existing electric motors during scheduled downtime with new, premium efficiency motors. Replacing 10 percent of failed or existing electric motors with "premium efficiency" motors could save the region 46 megawatts; enough to power the City of Auburn, Washington, for a year.
- **Retire Second Refrigerators:** Approximately one out of five homes in the region has two refrigerators. The average 10-year old refrigerator uses twice the electricity that new Energy Star models of the same size use, and the average 20-year refrigerator uses three times the electricity that new models use. Initiating a regional program to retire and properly recycle these refrigerators could result in significant regional savings. Some of these "second refrigerators" now are being used by consumers because their primary refrigerators are too small. This initiative should also offer a "two-for-one" trade in to encourage consumers to retire both their old refrigerators if they replace them with a new, and perhaps larger, but much more efficient Energy Star model. Every 10 percent reduction in the number of the region's "second refrigerators" could reduce the demand for electricity by approximately 5 to 7 average megawatts or enough electricity to supply half of the city of Cheney, Washington, for a year.
- **Accelerate Replacement of Existing Clothes Washers:** New Energy Star clothes washers use 35percent less electricity than models just meeting current federal minimum standards and 45 percent less than those built a decade ago. In addition, the new Energy Star models

typically use 35 to 45 percent less water, placing fewer demands on water and wastewater facilities. Initiating programs to promote the "early retirement" and recycling existing clothes washers could save substantial amounts of both energy and water. If just half of the new clothes washers sold in the region over the next twelve months meet the Energy Star standards, we can reduce regional electricity demand by about 5 average megawatts or enough to power the city of Weiser, Idaho, for a year. In addition, the region would reduce water use by 625 million gallons.

## **The Value of Public Leadership**

The approaches mentioned above essentially rely on utility programs and economic incentives to achieve reductions and shifts in demand. The value of public officials in educating the public about the nature and seriousness of the current situation and the contribution they can make to easing the power crunch should not be overlooked. Many of the actions that can help with the situation involve relatively minor changes in personal and corporate behavior – reducing thermostat settings slightly in the winter, reducing unnecessary lighting, turning off unused appliances and office equipment, slightly higher summer thermostat settings in air-conditioned buildings, to name a few. The Governors of Oregon and Washington have been particularly aggressive in calling for that kind of personal response. While it is difficult to tell with precision what quantitative impact those calls have had, there clearly has been some. It is also clear from observation that the message has not gotten through to everyone. Public leaders should continue to communicate the importance of personal and corporate action and lead by example.

## **Controlling the Market**

The extremely high electricity prices being experienced in the West, while a result of very unusual conditions, are nevertheless having significant effects on some parts of the regional economy. These effects can be expected to grow over the rest of this year as the wholesale price increases work their way further down into the economy through increases in retail prices. Some businesses have already closed because of high energy prices, creating increased unemployment and loss of income. In California, utilities teeter on the edge of bankruptcy. Low-income families are likely to be especially hard hit as retail prices begin to respond to the extremely high wholesale prices.

Concerns about the damage high prices are doing to the economy have led some to call for the Federal Energy Regulatory Commission (FERC) to reregulate wholesale power prices above a certain level throughout the West. They believe that temporary reregulation of wholesale electricity prices can be designed to allow a fair rate of return and at the same time to send a strong price signal that will encourage the development of more generation and cost-effective conservation. These parties argue, as well, that the economic impacts of recent extremely high prices on Northwest families, farms and industry are unacceptable and create unjustified profits for relatively few companies.

Others are strongly opposed to price controls. In general, economists and agencies that are charged with creating workable and efficient markets, such as the Federal Energy Regulatory Commission, are not enthusiastic about price controls. Opponents of price controls claim that they have been ineffective in a market setting, and that they tend to blunt the price signals that lead to market adjustments and are often circumvented by market participants. In addition, there are serious questions about our ability to effectively implement consistent price controls.

Regardless of the outcome of this debate, significant price increases are likely to occur. In view of the expected increase in electricity prices, state and local leaders should directly address the impacts on low-income consumers by expanding the scope and funding of existing programs. The impact on local business should be partially alleviated by publicizing and encouraging access to some of the types of demand management programs described above.

[^ top](#)